Performance

APF ENERGY TRUST

ANNUAL 2000 REPORT

Corporate Profile

APF Energy Trust *is an open-ended royalty trust created in December 1996 to provide unitholders with regular distributions based on the cash flow from producing oil and gas properties. Since commencing operations,* ***APF*** *has participated in approximately $200 million worth of oil and gas acquisitions and generated cumulative distributions of $8.05 per unit for the period ended May 15, 2001.*

ANNUAL GENERAL MEETING

The annual general meeting of unitholders of ***APF Energy Trust*** *will be held on Thursday, June 6, 2001 at 2:30 p.m. at The Sun Life Conference Centre at 210, 140 - 4th Avenue S.W., Calgary, Alberta.*

Bbl	Barrel
Bbls	Barrels
Bbl/d	Barrels per day
Mbbl	Thousand barrels
Bcf	Billion cubic feet
Mcf	Thousand cubic feet
Mcf/d	Thousand cubic feet per day
Mmcf	Million cubic feet
Mmcf/d	Millions of cubic feet per day
Boe	Barrel of oil equivalent (10 mcf = 1 bbl)
Boe/d	Barrels of oil equivalent per day
Mboe	Thousand barrels of oil equivalent
Mmbtu	Million British thermal units
NPV	Net present value
NGL	Natural gas liquid

Note: All currency is expressed in Canadian funds, except where otherwise indicated.

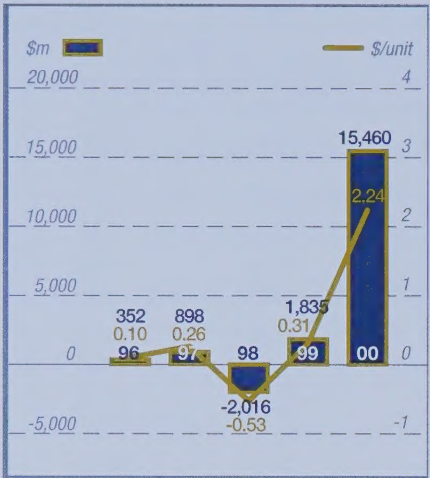
Corporate Highlights

	2000	1999	1998	1997	1996
PRODUCTION & PRICES					
Units Outstanding (000s)					
Year-end	**7,139**	5,890	5,890	3,500	3,500
Average	**6,888**	5,890	3,774	3,500	3,500
Daily Average Production					
Oil (bbls/day)	**1,152**	1,104	833	627	507
Natural gas (mcf/day)	**13,449**	13,656	15,219	14,977	6,621
NGLs (bbls/day)	**254**	274	303	252	96
Total (boe/day)	**2,751**	2,744	2,658	2,377	1,265
Annual (mboe)	**1,004**	1,002	970	867	38
Commodity Sales Prices (pre-hedge) ($)					
Oil (/bbl)	**42.67**	26.72	17.19	22.48	29.00
Natural gas (/mcf)	**4.89**	2.44	1.96	2.06	2.86
NGLs (/bbl)	**35.96**	18.19	16.24	22.20	31.36
Average (/boe)	**45.07**	24.69	18.45	21.24	28.98
Commodity Sales Prices (post-hedge) ($)					
Oil (/bbl)	**41.40**	25.00	18.18	22.48	29.00
Gas (/mcf)	**4.72**	2.36	2.04	2.06	2.86
NGLs (/bbl)	**35.96**	18.19	16.24	22.20	31.36
Average (/boe)	**43.72**	23.62	19.20	21.24	28.98
FINANCIAL					
Income Statement ($000s)					
Revenue					
Oil and natural gas sales	**44,047**	23,685	18,669	18,463	1,137
Other income	**928**	1,022	999	1,146	–
	44,975	24,707	19,668	19,608	1,137
Expenses					
Crown royalties	**4,405**	1,899	1,732	1,647	130
Non-Crown royalties	**4,125**	1,999	1,587	1,662	130
Operating costs	**8,021**	7,300	6,541	5,473	169
G&A	**1,844**	1,133	921	751	49
Management fee	**993**	465	337	375	20
Interest	**1,882**	1,955	2,079	1,183	31
Taxes	**164**	98	122	–	–
Depletion and depreciation	**7,175**	7,383	7,813	7,032	252
Site restoration	**905**	641	552	597	4
	29,514	22,872	21,684	18,710	785
Net income before unusual items	**15,461**	1,835	(2,016)	898	352
Unusual items	**210**	(6,524)	–	–	–
Net income after unusual items	**15,671**	(4,689)	(2,016)	898	352
Bank Debt ($000s)	**25,736**	33,171	23,823	21,900	4,100
Summary ($000s except per unit and per boe amounts)					
Revenue	**44,975**	24,707	19,668	19,608	1,137
Per unit	**6.53**	4.19	5.21	5.60	0.32
Operating cash flow	**28,424**	13,509	9,825	10,853	708
Per unit	**4.13**	2.29	2.60	3.10	0.20
Net income (before unusual items)	**15,460**	1,835	(1,999)	915	352
Per unit	**2.24**	0.31	(0.53)	0.26	0.10
Net income (after unusual items)	**15,671**	(4,689)	(1,999)	915	352
Per unit	**2.28**	(0.80)	(0.53)	0.26	0.10
Distributable income	**13,899**	9,188	5,538	6,213	601
Per unit	**1.65**	1.56	1.47	1.78	0.17
Distributions	**12,328**	8,452	4,831	4,550	–
Per unit	**1.90**	1.56	1.84	1.51	–
Operating costs per boe	**7.97**	7.29	6.74	6.33	4.00
Operating netback per boe	**28.25**	13.48	10.13	12.51	18.65
MARKET					
High	**$ 10.40**	$ 9.70	$ 9.75	$ 10.70	$ 6.80
Low	**$ 7.00**	$ 7.25	$ 7.65	$ 8.75	$ 5.90
Close	**$ 9.75**	$ 8.10	$ 8.00	$ 9.10	$ 6.65
Volume	**2,520,015**	2,393,558	1,230,666	2,415,470	1,050,49
Value	**$ 21,710,554**	$ 20,195,844	$ 10,763,660	$ 16,746,321	$ 6,892,053

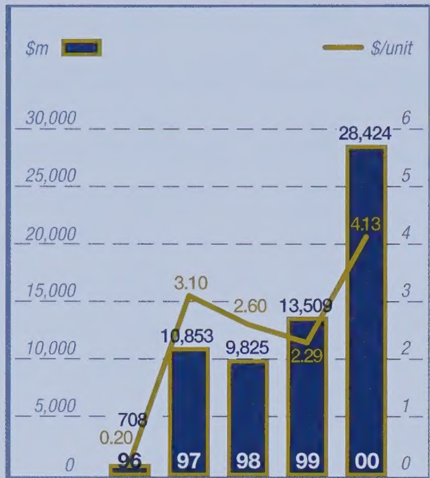
Notes:

(1) APF completed its initial public offering on December 17, 1996 at $10 per unit, comprised of a $6 installment receipt and the obligation to pay an additional $4 on August 1, 1997. Financial and operating figures for 1996 are for the one month ended December 31, 1996.

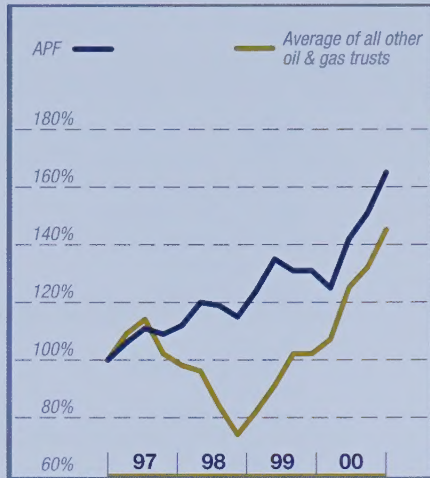
Performance Attributes



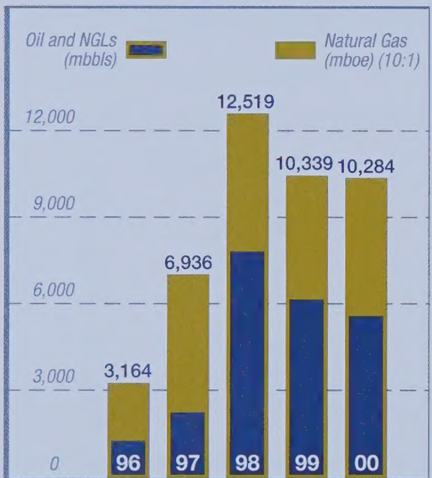
EARNINGS
(before unusual items)



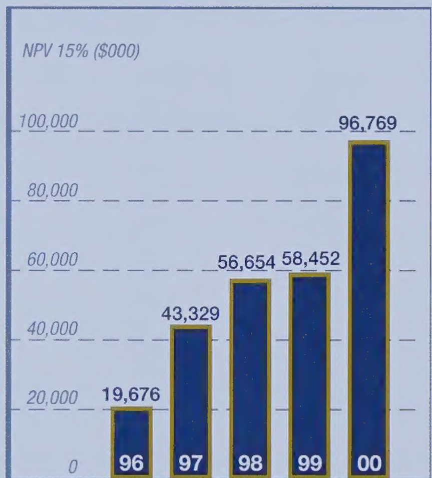
CASH FLOW



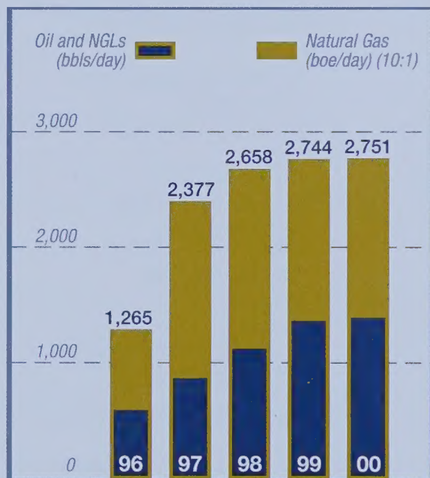
TOTAL RETURN
(since inception)



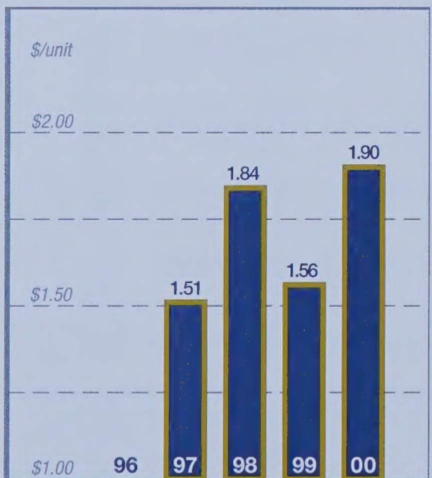
ESTABLISHED RESERVES
(proved plus risked probable)



ESTABLISHED RESERVES VALUE



PRODUCTION



DISTRIBUTIONS

2001 GOALS

- ***Integrate new production and operations from Alliance Energy acquisition.***
- ***Exploit development opportunities from acquisitions and existing properties.***
- ***Identify and evaluate new opportunities.***
- ***Maintain strong and competitive distributions to unitholders.***

Message to Unitholders

Based on a $10 investment on January 1, 1997, APF has led all other oil and gas trusts in distributions over a four-year period.

A TREMENDOUS YEAR FOR APF UNITHOLDERS

The year 2000 was a highly successful one for APF. Distributions per unit climbed to a record $1.90 and overall trust earnings increased by more than 700 percent to $15.5 million.

We believe that we delivered on our promise of "Staying the Course," the theme of last year's annual report. The hard work and dedication of our staff resulted in very successful development drilling programs and other optimization initiatives. By carefully harvesting opportunities within our existing portfolio of assets, we were able to replace 100 percent of our production, which remained stable at 2,751 boe per day.

The continued strength in the price of both commodities was an important factor to our success in 2000. During the year, APF realized an average price of $45.07 per boe for its oil, natural gas and natural gas liquids production, eclipsing last year's figure of $24.69 per boe. This pushed our operating netback to $28.25 per boe.

The impact of these factors led to distributions of $1.90 per unit, among the highest of all the oil and gas trusts. To benchmark that performance, as well as our historical distributions, we looked at the distributions of all conventional oil and gas trusts between January 1, 1997 and December 31, 2000. Based on a $10 investment on January 1, 1997, no other oil and gas trust paid more than APF over the four-year period.

MARCH 2000 EQUITY OFFERING

An important development in 2000 was APF's $8.9 million equity offering, completed in March. Despite still being in the midst of the high-tech frenzy, we issued 1.2 million units priced at $7.30 per unit. Unitholders who bought that issue have realized a one-year total return of 75 percent, which consisted of capital appreciation to $10.30 per unit as of late March 2001 plus distributions of $2.37 per unit.

TAKING ADVANTAGE OF NEW OPPORTUNITIES — MARCH 2001 EQUITY OFFERING

Since the price of crude oil began its remarkable recovery in January 1999 – pushing as high as US$37 per barrel in 2000 – only two components within the energy sector have found favour among investors: the multi-billion dollar exploration and production companies and the royalty trusts. Except for a few individual stories, everything else on the producers' side has been ignored.

The dichotomy of high commodity prices and low valuations for most small and medium-sized oil and gas companies presented a tremendous opportunity for APF to look at a wide range of under-valued targets. During the last year, we examined more than 60 corporate opportunities, making our way onto the short list of final bidders for several of these.

Recognizing the need to have the capital resources required to aggressively pursue selected transactions, we resolved to go to the equity markets with a new offering of units, and began preparing a prospectus in November 2000. APF's syndicate was led by Research Capital Corporation and included CIBC World Markets Inc., National Bank Financial Inc., Scotia Capital Inc., Dundee Securities Corporation and HSBC Securities (Canada) Inc. The presence of three new dealers – CIBC, Scotia and Dundee – provided additional support to what had been a very effective underwriting group since our initial public offering. The financing's net proceeds were to be used to finance future acquisitions as well as to fund ongoing development.

APF's mergers and acquisitions team will continue to identify and evaluate corporate and asset transactions.

By the time APF completed marketing in early February, we had exceeded our target of $25 million. Eventually, we closed on $33 million, issuing 3.305 million units at $10 per unit. The net proceeds went to eliminate net debt and will now be deployed to fund the Alliance acquisition and the follow-on acquisition of assets in Southeast Saskatchewan.

MOVING TO THE NEXT STEP: THE ACQUISITION OF ALLIANCE ENERGY

At the time of writing this annual report, APF had just completed a takeover of Alliance Energy Inc., a Calgary-based oil and gas company with production of approximately 1,600 boe per day. The transaction had a total value of $48 million, including the assumption of Alliance's bank debt. The purchase price was satisfied by a cash payment of $35.3 million and the issuance of 872,667 Trust units.

An even greater prize for APF will be realized in early May: the acquisition of another 2,000 barrels per day of light oil production, located in the middle of existing Alliance production in Southeast Saskatchewan. This opportunity was the result of Alliance entering into an agreement with another oil and gas company several months ago. We consider the acquisition of the Southeast Saskatchewan assets a tremendous opportunity. The purchase price of these assets, after adjustments, is expected to be approximately $41 million.

After these transactions are completed, APF will have acquired approximately 3,600 bbl per day of production at a cost of $89 million. We will more than double in size, and the new combined entity will have approximately $200 million in assets and daily production of 7,500 boe (gas converted at 6:1).

We look forward to reporting further on these exciting developments in the coming months. In the meantime, a more detailed discussion of the Alliance transaction is set out in this report's Management's Discussion and Analysis.

WHAT'S NEXT

The next several months will be very exciting and challenging for APF, as we integrate 3,600 bbls per day of new production and begin to harvest the many opportunities that come with the acquisitions. APF's mergers and acquisitions team will continue to identify and evaluate corporate and asset transactions that – like Alliance – we believe will be accretive to distributions. Along the way, our unitholders should continue to enjoy strong cash payouts.

ACKNOWLEDGEMENTS

We wish to acknowledge the dedication and hard work of our officers and staff over the past year, and to thank our independent Directors for their guidance. In particular, we wish to thank our now retired Chairman, Roy Gieck, for his contributions since we formed the Trust in late 1996. We also wish to welcome his replacement, Don Engle, to the Board, confident that he likewise will prove to be a valuable resource for our unitholders.

Steven Cloutier

Martin Hislop
President & CEO
April 19, 2001
Calgary, Alberta

Steve Cloutier
Executive Vice-President & COO

How the Trust Operates

Our goal is to provide unitholders with high and stable distributions.

GENERAL

APF Energy Trust is an open-end investment trust formed under the laws of the Province of Alberta for the purpose of acquiring a Royalty on oil and gas production.

On December 17, 1996, APF completed an initial public offering of 3.5 million Trust units at $10 per Trust unit, which were sold on an installment basis. Since then, APF has completed three public equity offerings: $18.1 million in December 1998 ($8.00 per unit); $8.9 million in March 2000 ($7.30 per unit); and $33 million in March 2001 ($10.00 per unit).

BUSINESS OBJECTIVES

The goal of the Manager is to provide the unitholders with high and stable cash contributions. To achieve this, APF must continually replace and add reserves through acquisitions, drilling and optimization initiatives.

In order to replace reserves and achieve growth, the Manager must be able to identify, evaluate and acquire oil and gas properties. To date, the Manager has demonstrated an ability to complete acquisitions on favourable terms, which have resulted in high and stable distributions for unitholders since the inception of APF. On a go-forward basis, the Manager will continue to use its internal expertise to identify potential acquisitions, but will also rely on financial advisors and other industry sources who are able to present opportunities. The ability of APF to complete these acquisitions will depend on its available credit facilities and on being able to raise equity from time to time.

DISTRIBUTABLE INCOME

Unitholders of record on a record date are entitled to receive monthly cash distributions of Distributable Income for the applicable production month. Distributable Income is paid to the unitholders 15 days following the applicable record date.

Under proposed amendments to the Alberta Corporate Tax Act, APF will not be entitled to ARC on Alberta Crown royalties paid or payable after December 31, 2000.

CORPORATE GOVERNANCE

Unitholders are entitled to elect a majority of APF's Board of Directors pursuant to the terms of a unanimous shareholder agreement. Subject to the ultimate authority of APF's Board of Directors, APF is managed by the Manager.

APF has a Board of Directors consisting of five individuals, three of whom are independent Directors, and two of whom were elected by the Manager.

MEETINGS AND VOTING

The Trust Indenture provides that annual meetings of the unitholders shall be held. Special meetings of unitholders may be called at any time by the Trustee upon the written request of unitholders holding in aggregate not less than 20 percent of the Trust units. Notice of all meetings of unitholders shall be given to unitholders at least 21 days prior to the meeting.

Unitholders may attend and vote at all meetings of such holders either in person or by proxy and a proxy holder need not be a holder of Trust units. Two persons present in person or represented by proxy and

representing in the aggregate not less than 10 percent of the votes attaching to all outstanding Trust units constitute a quorum for the transaction of business at all such meetings.

Unitholders are entitled to one vote per Trust unit at all meetings of unitholders called pursuant to the Trust Indenture. A special resolution is required to, among other things, substantively amend the Trust Indenture, remove the Trustee or terminate APF as a trust. A special resolution is also required to make substantive amendments to the material contracts of APF and to sell or agree to sell the property of APF (including the Royalty) as an entirety or substantially as an entirety.

TRUST UNITS

The Trust Indenture

A maximum of 500 million Trust units have been created and may be issued pursuant to the Trust Indenture. The Trust units represent beneficial interests in APF. All Trust units share equally in all distributions from APF and all Trust units carry equal voting rights at meetings of unitholders.

Voting Trust units and Principal Holders Thereof

As of April 19, 2001, 11,344,823 Trust units were issued and outstanding. Each Trust unit carries with it the right to one vote at meetings of unitholders.

To the best of the knowledge of the Manager, there is no person or corporation which beneficially owns, directly or indirectly, or exercises control or direction over Trust units carrying more than 10 percent of the voting rights attached to the issued and outstanding Trust units of APF.

The number of Trust units of APF that are owned, directly or indirectly, by the Manager, all directors and officers of the Manager and of APF and their associates as a group is 141,141 of the outstanding Trust units. In addition, the directors, officers and employees of APF and the Manager hold options entitling them as a group to acquire an additional 439,830 Trust units of APF.

DISTRIBUTIONS

APF distributes cash to unitholders on a monthly basis. During 1997 (the first year during which APF made distributions), 60.5 percent of cash distributions were tax deferred and for income tax purposes were treated as a return of capital, while the same figures for 1998 and 1999 were 75 percent and 66 percent, respectively. For 2000 cash distributions, 37.9 percent will not be subject to tax with 62.1 percent being taxable to unitholders.

In the past, APF has not paid out 100 percent of Distributable Income to unitholders, retaining a portion as is reasonably determined by the Manager to, among other things, fund capital expenditure or acquisitions, stabilize future distributions or temporarily reduce indebtedness to APF's bankers.

The following per Trust unit cash distributions have been received by unitholders during the periods indicated:

1997	$	1.510
1998	$	1.840
1999	$	1.555
2000		
January 15	$	0.125
February 15	$	0.125
March 15	$	0.125
April 15	$	0.125
May 15	$	0.125
June 15	$	0.135
July 15	$	0.135
August 15	$	0.135
September 15	$	0.140
October 15	$	0.210
November 15	$	0.210
December 15	$	0.310
2000 TOTAL	**$**	**1.900**
2001		
January 15	$	0.220
February 15	$	0.250
March 15	$	0.250
April 15	$	0.225
May 15	$	0.300
TOTAL ALL YEARS	**$**	**8.050**

Note: (1) The initial public offering of APF was completed on December 17, 1996. The first cash distribution was made to unitholders on January 31, 1997.

TRADING HISTORY

The outstanding Trust units are listed and posted for trading on The Toronto Stock Exchange (TSE). The following table sets forth the high, low and closing prices and the aggregate volume of trading of the Trust units on the TSE for the periods indicated.

THE TORONTO STOCK EXCHANGE

Period	High	Low	Closing	Volume
1998				
Fourth Quarter	$ 8.95	$ 7.65	$ 8.00	404,076
1999				
First Quarter	8.65	8.00	8.50	477,650
Second Quarter	9.35	8.40	9.25	690,303
Third Quarter	9.70	8.35	8.45	653,126
Fourth Quarter	8.25	7.25	8.10	219,638
2000				
First Quarter	8.20	7.05	7.05	331,771
Second Quarter	8.70	7.00	8.45	466,103
July	8.70	8.10	8.20	285,649
August	9.05	8.10	8.70	202,873
September	9.45	8.50	9.10	327,278
October	9.15	8.50	8.60	390,766
November	9.85	8.50	9.50	284,292
December	10.40	9.50	9.75	230,633
2001				
January	10.70	9.65	10.10	895,891
February	10.70	10.00	10.00	734,400
March	10.44	9.75	10.00	910,093
April 1-17	$ 11.32	$ 9.85	$ 11.32	660,683

Operations Review

Properties	Average Percent Interest(1)	Company Interest Reserves(2)(3)	Estimated Net Production 2001(3)(6)	Reserve Life(3)(4)	Asset Value(3)(5)	
		(mboe)	(boe/day)	(years)	($000s)	%
Countess	79.3	2,643	817	27	34,288	35.4
Redwater	59.8	1,055	553	39	22,167	22.9
Pembina	4.8	3,563	464	50	15,562	16.1
Wayne-Rosedale	87.5	1,029	292	50	6,344	6.6
Girouxville	15.0	211	152	16	2,846	2.9
Joarcam	8.8	511	161	38	4,956	5.1
Other properties	0.7	1,272	397	49	10,606	11.0
TOTAL		10,284	2,836		96,769	100.0

Notes:

(1) The percentage company interest owned by APF in the properties is based on its share of established reserves, including working interest and overriding royalty interest.

(2) The company interest share of recoverable reserves before the deduction of royalties.

(3) Based on established reserves outlined in the Gilbert Report.

(4) Reserve life is the time remaining during which production is forecast to be economic.

(5) Discounted at 15 percent and based on the escalated price and cost forecast contained in the Gilbert Report. ARC is included, where applicable.

(6) The average production rate for 2001 as outlined in the Gilbert Report.

PRINCIPAL PRODUCING PROPERTIES

APF's properties include both unitized and non-unitized oil and natural gas production. The properties contain long-life reserves. Of the present value of the estimated future net cash flow from the properties, approximately 89 percent is located in six core areas as outlined in the table opposite.

Set out below is a description of the principal properties, by area. The terms "net" and "net working interest share" where used in the description of the properties means the working interest share owned by APF. The term "reserves" unless otherwise stated, refers to the oil, natural gas and/or NGLs remaining to be recovered as of January 1, 2001. Annual production estimates, estimated remaining reserves, ultimate recovery estimates, future production rates and working interests in the following property descriptions are derived from the Gilbert Report, unless otherwise stated. See "Oil and Natural Gas Reserves."

Countess, Alberta

The Countess area in southeast Alberta comprises both the Leckie and Countess properties where APF has production from a total of 327 natural gas wells.

At Leckie, dry natural gas is produced from the shallow sands of the Belly River, Milk River and Medicine Hat formations. APF has a 100 percent working interest in 22,880 acres and a 100 percent interest in a compressor station. Production during 2001 is expected to average 4,013 mcf per day. During the past two years, 16 wells have been drilled by APF for production from the Milk River and Medicine Hat formations. The new wells cost $130,000 each to drill, complete and tie in. Field infrastructure was also expanded in 2000, to accommodate the current and future drilling program. Natural gas is gathered, dehydrated and compressed in the field and sold under long-term contract to TransCanada Gas Services. APF receives custom compression revenue from surplus capacity in the two 720-horsepower compressors.

APF has an average working interest of 75.2 percent in 24,960 acres of land at Countess, which contain predominantly shallow, dry natural gas production from the Belly River, Milk River and Medicine Hat formations. Production from the property commenced in 1976. There have been several development drilling programs with the most recent completed in 1995. Production is expected to average 4,127 mcf per day during 2001.

Additional potential exists for further infill drilling by reducing well spacing to 80 acres at both Countess and Leckie. A 20-well program is planned for 2001.

Redwater, Alberta

The Redwater area northeast of Edmonton, Alberta comprises the Redwater, Abee West, Radway, Newbrook and Thorhild properties. These were acquired in November 2000 from Grey Wolf Exploration Inc. (Greywolf). The $14 million purchase price was satisfied by APF swapping certain oil and gas interests it owned in the Caroline area of Alberta. APF also received $500,000 of cash.

APF has an average 60 percent working interest in 65 producing wells covering approximately 148 sections of land. Production during 2001 is expected to average 5,534 mcf per day from the Wabamun, Detrital, Basal Quartz, Glauconitic, Colony, Second White Specks and Sparky zones. The production is sold under a combination of short- and long-term natural gas contracts and on the spot market.

Pembina, Alberta

APF has interests in six Pembina Cardium units located approximately 70 miles southwest of Edmonton. Light crude oil is currently produced from 542 wells under waterflood programs in the Cardium Formation in each of the units. Oil is treated at batteries associated with each unit. Solution natural gas is gathered and processed through APF's share of the Pembalta gathering system.

APF owns a 1.26 percent working interest in the North Pembina Cardium Unit No. 1 which is operated by Mobil Oil Canada Inc. and has been on a waterflood since the early 1960s. The wells are producing on 80-acre spacing. The Unit has undergone extensive production optimization, primarily in the late 1980s and early 1990s, which included selective cement squeezes and packer isolation techniques to control water production and injection, refracturing and re-perforating. More recently, in late 1995 and 1996, a total of 10 horizontal re-entries were drilled. During 2000, an extensive waterflood realignment project was implemented. Mobil has indicated that there is considerable potential for additional horizontal drilling that targets the low- to medium-permeability layers of the reservoir. There is also potential to refracture additional wells.

APF has a 7.35 percent working interest in the Pembina Cardium Unit No. 12, which is operated by ARC Resources Ltd. There are currently 77 producing oil wells in this unit. Since 1999, 13 wells have been drilled on 80-acre spacing, doubling production from the Unit. Development plans for 2001 will be primarily focused on refracture stimulations of existing wells. Potential exists for additional drilling on 80-acre spacing.

APF owns a 100 percent working interest in the Pembina Cardium Unit No. 20, which has 10 producing oil wells and four water injectors, drilled on 80-acre spacing. Upside potential exists through refracturing existing wells and optimizing waterflood performance. During 2000, one well was whipstocked and fracture stimulated, adding 35 bbls per day of production.

APF has a 5.15 percent working interest in the Pembina Cardium Unit No. 9, operated by Penn West Petroleum Ltd., which has 114 producing oil wells. Most of the north area of the Unit is on 80-acre spacing oriented in a line-drive pattern. Four wells were drilled on 80-acre spacing during 2000 in the southwest part of the Unit. Downspacing will continue during 2001.

APF owns and operates a 100 percent working interest in the Champlin-Peruvian Cardium Unit No. 1 that has produced under waterflood since 1962. Currently, the Unit includes seven producing wells and two injectors. Plans for 2001 including drilling two 80-acre infill wells and converting one well to water injection. Additional potential exists to fracture-stimulate existing wells and continue 80-acre downspacing.

Wayne-Rosedale, Alberta

APF owns a 100 percent working interest in 30 producing wells and a 37.5 percent working interest in one producing well in the Wayne-Rosedale area, located approximately 10 miles south of Drumheller. The wells produce 29° API oil from the Basal Quartz Formation. The pool was discovered in 1954 and a waterflood was initiated in the northern part of the pool in 1970. Although initially developed on 80-acre spacing, infill wells drilled during 1985 and 1986 reduced spacing to 40 acres in a portion of the pool. Development potential for the field includes stepout drilling and restimulating existing wells.

Girouxville, Alberta

APF owns a 15 percent working interest in 18.5 sections of land at Girouxville, which is located 225 kilometres northwest of Edmonton. The Girouxville Beaverhill Lake B pool was discovered in 1998. APF acquired an interest in the pool in February 1999. During 1999, six wells were drilled, a waterflood was implemented and natural gas conservation facilities were installed. The pool has been on good production practice since October 1999. Currently, the pool consists of three oil producers. Potential exists for stepout drilling.

Joarcam, Alberta

APF owns various unitized and non-unitized interests in this area, located approximately 57 kilometres southeast of Edmonton where production is currently coming from 53 oil wells and eight natural gas wells. The Company owns a 27 percent working interest in 240 acres in Section 1-50-22 W4M, where six non-unit Viking wells operated by Zargon Oil & Gas Ltd. are currently on production. APF also has a 75 percent interest in one other Viking oil well and an average 27 percent interest in six natural gas wells in the area.

APF owns a 2.5 percent working interest in the Joarcam Viking Unit No. 3, formed in 1967. The Unit is producing under a pattern waterflood, which has resulted in a high oil recovery factor. EnerMark Inc. is the operator.

APF owns an eight percent working interest in the Joarcam Viking Gas Cap Unit. This Unit was formed in 1993 to promote the orderly blow-down of the natural gas cap associated with the Joarcam Viking oil pool, and to conserve solution natural gas. EnerMark Inc. is the Unit operator. Unit production is restricted by the AEUB to provide pressure maintenance for the oil in the Joarcam Viking Pool.

FACILITIES

The following table sets out major facilities in which APF has an interest.

Area Name	Major Facilities*	
Countess, Alberta	Forty-two percent interest in the Countess natural gas plant; 100 percent interest in the Countess-Leckie compressor and four booster compressors.	
Redwater, Alberta	Interests in natural gas facilities as follows:	
	90 percent	Radway compression
	50 percent	Redwater 8-9 compression and dehydration
	50 percent	Redwater 13-27 compression and dehydration
Joarcam, Alberta	Forty percent interest in the Joarcam natural gas plant; eight percent interest in the Joarcam Viking natural gas plant; 2.5 percent interest in the Viking Oil Unit No. 3 battery; 27.4 percent interest in the Joseph Lake oil battery.	
Wayne-Rosedale, Alberta	One hundred percent interest in the Wayne-Rosedale oil battery.	
Girouxville, Alberta	Fifteen percent interest in the Girouxville oil battery and gas conservation facility.	
Pembina, Alberta	Interests in unit oil treating and water injection facilities as follows:	
	1.26 percent	North Pembina Cardium Unit
	7.35 percent	Pembina Cardium Unit No. 12
	100 percent	Pembina Cardium Unit No. 20
	5.15 percent	Pembina Cardium Unit 9
	65.78 percent	Champlin-Peruvian Cardium Unit
	Interests in natural gas processing facilities as follows:	
	0.52 percent	Pembalta No. 1
	0.66 percent	Pembalta No. 2
	1.10 percent	Pembalta No. 3
	2.66 percent	Pembalta No. 4
	0.10 percent	Pembalta No. 5
	1.21 percent	Pembalta No. 7
	0.47 percent	Pembalta No. 8

"Major Facilities" includes only significant processing facilities and pipelines associated with the designated area.

OIL AND NATURAL GAS RESERVES

Gilbert Laustsen Jung Associates Ltd. (Gilbert), independent petroleum consultants, prepared a report on the reserves attributable to APF's properties and the present value of the estimated future net cash flow associated with such reserves effective January 1, 2001.

SUMMARY OF RESERVES AT DECEMBER 31, 2000

	Working Interest Reserves						Present Value of Estimated Future Net Cash Flow at Discount Rate of[3]			
	Gross[1]			Net[2]						
	Oil	Natural Gas	NGLs	Oil	Natural Gas	NGLs	0%	10%	15%	20%
	(mbbl)	(mmcf)	(mbbl)	(mbbl)	(mmcf)	(mbbl)	($000s)			
Proved										
Producing[4][5]	4,249	32,844	351	3,709	26,853	257	144,166	89,196	77,522	69,250
Non-producing[4][6]	242	5,658	22	236	4,678	15	20,987	11,495	9,583	8,252
Total proved	4,491	38,502	373	3,946	31,531	272	165,153	100,691	87,105	77,501
Risked probable[7]	721	7,862	63	612	6,361	45	31,888	12,803	9,664	7,646
Established	5,212	46,364	436	4,558	37,892	317	197,041	113,494	96,769	85,147

(columns may not add due to rounding)

Note:

(1) "Gross Working Interest Reserves" means the working and overriding royalty interest share of remaining recoverable reserves before deduction of royalties.

(2) "Net Working Interest Reserves" are Gross Working Interest Reserves less all lessor and overriding royalties and interests owned by others.

(3) The net cumulative cash flow forecasts are after direct lifting costs, royalties, mineral taxes and future capital investments but before general and administrative expenses, management fees, debt service charges and income taxes. Well abandonment and site restoration costs were included in the cash flow and net present value estimates as well as Alberta natural gas cost allowance and Jumping Pound allowances on remaining undepreciated capital bases and income from custom processing fees. ARC has been included, where applicable.

(4) "Proved Reserves" are those reserves estimated as recoverable with a high degree of certainty under current technology and existing economic conditions in the case of constant price and cost analyses and anticipated economic conditions in the case of escalated price and cost analyses, from that portion of a reservoir which can be reasonably evaluated as economically productive on the basis of analysis of drilling, geological, geophysical and engineering data, including the reserves to be obtained by enhanced recovery processes demonstrated to be economic and technically successful in the subject reservoir.

(5) "Producing Reserves" are those reserves that are actually on production and could be recovered from existing wells and facilities or, if facilities have not been installed, that would involve a small investment relative to cash flow. In multi-well pools involving a competitive situation, reserves may be subdivided into producing and non-producing reserves in order to reflect allocation of reserves to specific wells and their respective development status.

(6) "Non-Producing Reserves" are those reserves that are not classified as producing.

(7) "Probable Reserves" are those reserves which analysis of drilling, geological, geophysical and engineering data does not demonstrate to be proved, but where such analysis suggests the likelihood of their existence and future recovery under current technology and existing or anticipated economic conditions. Probable additional reserves to be obtained by the application of enhanced recovery processes will be the increased recovery over and above that estimated in the proved category which can be realistically estimated for the pool on the basis of enhanced recovery processes which can be reasonably expected to be instituted in the future.

(8) The pricing assumptions used in the Gilbert Report with respect to the cumulative net cash flow (escalated) as well as the inflation rates used or operating costs are set forth opposite.

		W.T.I. Crude Oil at Cushing Oklahoma	Light, Sweet Crude Oil (40° API, 0.3%) at Edmonton	Alberta NGLs (Then Current Dollars)			
	Exchange Rate	Then Current	Then Current	Spec Ethane	Edmonton Propane	Edmonton Butane	Pentanes Plus
Year	$US/CDN	$US/bbl	$CDN/bbl	$CDN/bbl	$CDN/bbl	$CDN/bbl	$CDN/bbl
2001	0.66	27.00	40.25	23.25	27.00	30.75	41.75
2002	0.66	24.00	35.25	17.00	24.25	25.25	36.25
2003	0.67	21.00	30.25	15.25	19.25	20.25	30.75
2004	0.68	21.00	29.75	14.50	18.75	19.75	29.75
2005	0.69	21.25	29.75	14.50	18.75	19.75	29.75
2006	0.70	21.75	29.75	14.25	18.75	19.75	29.75
2007	0.71	22.00	29.75	14.00	18.75	19.75	29.75
2008	0.72	22.25	29.75	14.00	18.75	19.75	29.75
2009	0.72	22.50	30.25	14.25	19.25	20.25	30.25
2010	0.72	23.00	30.75	14.50	19.75	20.75	30.75
2011	0.72	23.25	31.25	14.75	20.00	21.25	31.25
2012	0.72	*Escalate at 1.5 percent per year*					

	AECO-C Spot Then Current	Average Then Current	Spot[9b]	Aggregator	Alliance
Year	$CDN/mmbtu	$CDN/mmbtu	$CDN/mmbtu	$CDN/mmbtu	$CDN/mmbtu
2001	7.50	6.70	7.30	5.30	6.45
2002	5.60	4.85	5.40	4.20	4.70
2003	4.80	4.35	4.60	4.00	4.00
2004	4.65	4.20	4.45	3.85	3.95
2005	4.40	4.20	4.20	4.20	3.85
2006	4.30	4.10	4.10	4.10	3.80
2007	4.25	4.05	4.05	4.05	3.80
2008	4.25	4.05	4.05	4.05	3.80
2009	4.30	4.10	4.10	4.10	3.85
2010	4.40	4.20	4.20	4.20	3.95
2011	4.45	4.25	4.25	4.25	4.00
2012	*Escalate at 1.5 percent per year*				

Comments regarding pricing assumptions:

(9) a) Unless otherwise stated, the gas price reference point is the receipt point on the applicable provincial gas transmission system, known as the plant gate. The plant gate price represents the price before raw gas gathering and processing charges are deducted.

b) Spot refers to weighted average one-month price.

(10) Operating and capital costs were escalated from 2001 base levels at a rate of 1.5 percent per year.

(11) The Gilbert Report has estimated total capital costs of $7,916,000 (undiscounted) in order to achieve the future net cash flow from Established Reserves in the escalated price case.

(12) The Gilbert Report adjusted the base product prices to reflect property specific factors: for example crude quality differentials, natural gas BTU content, transportation tariffs and the details of product sales contracts.

(13) All of the proved producing reserves are currently on production.

RECONCILIATION OF RESERVES

The following table contains management's reconciliation of APF's established reserves, as set out in the Gilbert Report, to established reserves as at the year ended December 31, 2000:

	Oil (mbbl)	Natural Gas (bcf)	NGLs (mbbl)	Total (mboe)(1)
Reserves at December 31, 1999	5,298	41.4	918	10,339
Acquisitions	92	11.1	5	1,207
Drilling and development	269	5.4	32	840
Divestitures	(1)	(8.0)	(446)	(1,236)
Production	(410)	(4.8)	(66)	(954)
Revisions	(35)	1.3	(7)	88
Reserves per Gilbert Report	5,213	46.4	436	10,284

Note:

(1) Oil equivalent volumes are approximate due to variations in NGL equivalence factors.

DRILLING HISTORY

The following table sets forth the drilling activity for APF for the periods indicated:

Years Ended December 31	**2000**		1999		1998	
	Gross(1)	**Net(2)**	Gross(1)	Net(2)	Gross(1)	Net(2)
Oil	**33**	**3.17**	17	1.03	26	0.30
Natural gas	**65**	**14.84**	6	6.00	29	0.80
Dry wells	**–**	**–**	14	0.07	–	–
Other	**27**	**0.53**	38	0.67	–	–
TOTAL	**125**	**18.54**	75	7.77	55	1.10

Notes:

(1) "Gross" wells means the number of wells in which APF has an interest.

(2) "Net" wells means the aggregate of the numbers obtained by multiplying each gross well by the percentage working interest of APF therein.

CAPITAL EXPENDITURES

The following table summarizes APF's capital expenditures for the periods indicated:

Years Ended December 31	**2000**	1999	1998
Property acquisition	**$ 13,248,833**	$ 3,895,223	$ 27,900,314
Land acquisition	**146,522**	143,297	130,051
Seismic	**15,292**	98,572	62,160
Drilling and completions	**3,868,555**	2,231,638	584,805
Production facilities	**1,618,772**	949,749	500,427
Abandonment	**43,544**	231,591	163,654
Other	**–**	5,480	(286,065)
SUBTOTAL	**18,941,518**	7,555,550	29,055,346
Dispositions (including swaps)	**12,392,879**	2,326,397	7,333,924
NET CAPITAL EXPENDITURES	**$ 6,548,639**	$ 5,229,153	$ 21,721,422

PRODUCING WELLS

The numbers of wells on the principal properties in which APF has an interest as at January 1, 2001 and which it considers capable of production are set out in the following table:

	Producing[1][6]				Shut-in[2]				Other[5]	
	Oil		Gas		Oil		Gas			
	Gross[3]	Net[4]	Gross[3]	Net[4]	Gross[3]	Net[4]	Gross[3]	Net[4]	Gross[3]	Net[4]
Countess	–	–	327	276	–	–	10	8	1	1
Pembina	542	28	–	–	120	4	–	–	229	14
Redwater	–	–	65	25	–	–	44	18	–	–
Girouxville	3	1	–	–	1	0	–	–	4	1
Wayne-Rosedale	31	30	–	–	11	–	–	–	1	1
Joarcam	53	4	8	2	9	1	4	1	25	1
TOTAL	629	63	400	303	141	5	58	27	260	18

Notes:

(1) Information provided by APF, which includes changes on the properties since the Gilbert Report.

(2) "Shut-in" wells means wells which are not producing but which APF considers to be capable of production.

(3) "Gross" wells means the number of wells on the properties in which APF has an interest.

(4) "Net" wells means the number of gross wells multiplied by the net working interest share of APF therein.

(5) "Other" wells includes injection wells, disposal wells and service wells.

(6) All wells that are assigned proved non-producing reserves are within economic distance of gathering systems, pipelines or other means of transportation.

UNDRILLED ACREAGE

No value has been attributed to undeveloped acres owned by APF as follows: 88,907 gross (33,329 net) acres in Alberta and 7,735 gross (617 net) acres in Saskatchewan.

MARKETING ARRANGEMENTS

As at January 1, 2001, APF's production mix was approximately 57 percent natural gas and 43 percent crude oil and NGLs. Except for Redwater, where gas is predominantly sold on the spot market or into short-term contracts, the balance of gas production (approximately 60 percent) is sold to aggregators pursuant to long-term contracts. The forecast prices are set forth above, at "Oil and Natural Gas Reserves," at Note 8, relating to pricing assumptions. During 2000, APF received an average of $4.72 per mcf for its natural gas, after hedging. APF's crude oil and NGLs were sold on a combination of short-term and spot contracts, which averaged $41.40 per bbl and $35.96 per bbl, respectively, after hedging.

APF received an average price of $45.07 per boe, generating record financial results.

GENERAL DISCUSSION

Commodity prices continued to remain strong in 2000. Oil moved through the US$30 per bbl level as events in the international markets continued to cause uncertainty about world crude supply. Meanwhile, natural gas experienced an even more remarkable increase, on the strength of a declining North American ability to replace reserves and higher than expected demand.

As prices moved higher, the Manager took the opportunity to hedge a modest portion of both its oil and gas production, in order to protect against unforeseen erosions in price. These hedging activities have and will continue to ensure the stability of a portion of APF's distributions.

As most of APF's commodity sales are linked to U.S. dollar benchmarks, movement in foreign exchange rates impact on Distributable Income; in particular, APF tends to benefit from a weaker Canadian dollar. In fact, the Canadian dollar remained fairly weak during the year.

The Manager uses its judgement, based on information in the public domain about what is expected to happen in the future with respect to interest rates, commodity prices and foreign exchange rates, in order to anticipate the effect on the amount, timing or certainty of cash flow.

PRODUCTION

APF averaged 2,751 boe per day of production during 2000, consisting of 13,449 mcf per day of natural gas, 1,152 bbls per day of oil and 254 bbls per day of NGLs, compared with 2,744 boe per day in 1999. Overall production levels were sustained as a result of very successful development drilling programs at Countess and Pembina, despite the fact that no material acquisitions were made. Based on average daily volumes, APF's production mix was relatively balanced, at 49 percent natural gas and 51 percent oil and NGLs.

REVENUE

APF received an average price of $45.07 per boe for its commodities before hedging ($43.72 per boe after hedging). This was comprised of $42.67 per bbl for oil ($41.40 per bbl after hedging), $4.89 per mcf for natural gas ($4.72 per mcf after hedging) and $35.96 per bbl for NGLs. The overall increase of 83 percent compared to last year's average price of $24.69 per boe was indicative of the continued and sustained strengthening of both oil and gas prices.

Reflecting higher commodity prices and stable production, revenue for 2000 increased by 82 percent to $45 million from $24.7 million in 1999. On a per Trust unit basis, revenue increased from $4.19 per Trust unit in 1999 to $6.53 per Trust unit in 2000. Operating cash flow more than doubled to $28.4 million ($4.13 per Trust unit) compared to $13.5 million ($2.29 per Trust unit) in 1999. On an operating netback basis, APF generated $28.25 per boe, compared to $13.48 per boe a year earlier. APF's bottom line improved by 743 percent, as operating income (before unusual items) increased from $1.8 million in 1999 to $15.5 million in 2000.

CASH DISTRIBUTIONS

Distributable Income in 2000, before the working capital reserve, amounted to $14.4 million or $2.10 per Trust unit, versus $9.5 million or $1.62 per unit in 1999. Of that, $1.90 per Trust unit was paid to unitholders, surpassing the 1999 distribution of $1.56 per Trust unit.

During the year, APF maintained its policy of not paying out 100 percent of Distributable Income, retaining $0.5 million to initially reduce debt and subsequently to fund capital expenditures and development initiatives. Since the creation of APF in December 1996, the aggregate surplus which APF has reinvested amounts to $3.4 million.

Of the $1.90 per unit paid during 2000, 37.9 percent was considered a return of capital, while the balance was income.

OPERATING COSTS

Operating costs amounted to $8.0 million ($7.97 per boe of production) during 2000, up from $7.3 million ($7.29 per boe) in 1999. Although the Manager had hoped to decrease overall operating costs, continued high costs at a number of non-operated properties in the Pembina area contributed to the increase. Although management actively reviews operating procedures of both operated and non-operated production, it is expected that APF's assets at Pembina will continue to bring up the overall average. Absent Pembina, APF's operating costs per boe during 2000 were approximately $7.00.

MANAGEMENT FEES AND GENERAL AND ADMINISTRATIVE EXPENSES (G&A)

The Manager receives a fee equal to 3.5 percent of net production revenue. For the year ended December 31, 2000, a fee of $1.0 million ($0.99 per boe of production) was paid. In 1999, the Manager received fees of $0.5 million ($0.46 per boe). The increase from the previous year's fees was the direct result of extremely strong commodity prices and the resulting impact on revenues. G&A charged by the Manager to APF was $1.8 million ($1.83 per boe) compared to $1.1 million ($1.13 per boe) in 1999, largely reflecting the hiring of new staff, as well as the incremental cost of additional office space to accommodate the expansion of personnel. Total administrative expenses (management fees plus G&A) averaged $2.82 per boe in 2000, versus $1.59 per boe in 1999.

A structuring fee of 1.5 percent was paid to the Manager on the 2000 acquisitions, amounting in aggregate to $0.3 million, versus $0.1 million in 1999. The increase was attributable to the acquisition of the Redwater assets and divestiture of the Caroline property in December. This fee has been capitalized and is included in the adjusted purchase and sale prices of the properties.

INTEREST EXPENSE

APF's long-term debt stood at $33.2 million at the beginning of 2000. This was reduced by the net proceeds from the $8.9 million equity issue completed by APF in March 2000 (see Liquidity, Capital Resources and Equity Financings, below). During the year, the cash portion of APF's 2000 acquisitions and capital expenditures on existing oil and natural gas assets was funded from APF's available credit facilities with its bankers. As a result, interest expense for the period amounted to $1.8 million, compared to $2.0 million in 1999. By December 31, 2000, the total outstanding to APF's bankers amounted to $25.7 million.

LIQUIDITY, CAPITAL RESOURCES AND EQUITY FINANCINGS

APF has an operating and acquisition facility with its bankers. The limit of this facility has increased from time to time to reflect the growth in APF's asset base. At December 31, 2000, APF's indebtedness amounted to $25.7 million, on an authorized limit of $42 million. As a result of recent acquisitions, APF has received approval for a new $80 million credit facility, of which approximately $25 million is currently drawn.

On March 15, 2000, APF completed an equity financing, issuing 1.22 million Trust units at a price of $7.30 per Trust unit, for gross proceeds of $8.9 million. The funds were initially used to reduce bank indebtedness, and ultimately provided the capital for APF's development projects during the year. By December 31, 2000, APF had 7.14 million Trust units outstanding and a market capitalization of approximately $71 million. In March 2001, APF completed another

equity financing, issuing 3.3 million Trust units at a price of $10.00 per Trust unit, for gross proceeds of $33 million. These funds were initially used to reduce bank indebtedness, and it is intended that they ultimately will be deployed to finance the acquisitions. The Trust had an aggregate of 11.3 million Trust units outstanding.

CAPITAL EXPENDITURES

Total net capital expenditures during the year were $6.5 million, comprised of $1.9 million of net properties acquired and $4.6 million of other capital expenditures. The most significant transaction during 2000 was the swap of APF's Caroline assets for a package of high working-interest natural gas properties in the Redwater area northeast of Edmonton in December. Although the transaction was valued by APF at more than $13.5 million, the net financial effect (after purchase price adjustments and the exercise of certain rights of first refusal by third parties) was a straight-up swap.

ACQUISITION OF ALLIANCE ENERGY INC.

On April 11, 2001, APF completed the acquisition of Alliance Energy Inc. (Alliance), paying $2.02 per share for 21.9 million common shares for a total of $44.2 million. The purchase price was satisfied by the payment of $35.3 million in cash and the issuance of 868,079 APF Trust units at a deemed price of $10.05 per unit. Together with the assumption of Alliance's existing debt, the total transaction was valued at approximately $48 million. Alliance was a Calgary-based oil and gas company whose operations were focused in Southeast Saskatchewan. The acquisition added approximately 1,600 bbls per day of light oil, almost all of which is operated.

Prior to entering into the agreement to acquire Alliance, Alliance itself had agreed to acquire another 2,000 bbls of oil per day in close proximity to its existing properties, from a senior oil and gas producer, for approximately $41 million (after adjustments). Closing is expected to occur on April 30, 2001, and APF will now complete that transaction, drawing on its available credit facilities. Once all of the transactions have been completed, APF will have acquired 3,600 bbls of oil per day for approximately $88 million or $24,700 per flowing bbl. On a pro forma basis, total daily production for APF will increase from 3,900 boe per day to 7,500, (gas converted at 6 to 1 ratio), consisting of 16.3 mmcf per day of gas and 4,800 bbls per day of oil and liquids.

Management's Report

APF Energy Management Inc., as manager of APF Energy Trust and APF Energy Inc., is responsible for the preparation of the combined financial statements and the preparation of all other financial information included in the annual report. The combined financial statements have been prepared in accordance with Canadian generally accepted accounting principles, and where applicable, amounts based on management's best estimates and judgement.

Management has established procedures and systems of internal control designed to provide reasonable assurance that assets are safeguarded and that accurate financial information is produced in a timely manner.

The Board of Directors is responsible for reviewing and approving the combined financial statements, and through its Audit Committee, ensuring that management fulfills its responsibilities for financial reporting. The Audit Committee, which is comprised of three independent directors, meets periodically with management and the external auditors to satisfy itself that each party is properly discharging its responsibilities. The Audit Committee reviews the combined financial statements and recommends their approval to the Board of Directors. PricewaterhouseCoopers LLP, an independent firm of Chartered Accountants, appointed by the unitholders of APF Energy Trust, have audited the combined financial statements in accordance with generally accepted auditing standards. PricewaterhouseCoopers LLP have full and free access to the Audit Committee.

Martin Hislop
President & C.E.O.
Calgary, Alberta
April 17, 2001

Steven Cloutier

Steven Cloutier
Executive Vice President & C.O.O.

Auditors' Report

To the Trustee of APF Energy Trust and the Directors of APF Energy Inc.

We have audited the combined balance sheets of APF Energy Trust as at December 31, 2000 and 1999 and the combined statements of operations and retained earnings (deficit), cash flows and royalty distribution for the years ended December 31, 2000 and 1999. These financial statements are the responsibility of the Trust's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these combined financial statements present fairly, in all material respects, the financial position of the Trust as at December 31, 2000 and 1999 and the results of its operations and its cash flows for the years ended December 31, 2000 and 1999 in accordance with Canadian generally accepted accounting principles.

PricewaterhouseCoopers LLP

PricewaterhouseCoopers LLP
Chartered Accountants
Calgary, Alberta
March 14, 2001

Combined Balance Sheet

December 31	APF Energy Inc.	APF Energy Trust	**2000**	1999
ASSETS				
Current assets				
Cash	$ (119,612)	$ 185,843	**$ 66,231**	$ 96,550
Accounts receivable	7,196,573	246,712	**7,443,285**	4,075,296
Due (to) from APF Trust/Energy	(5,002,572)	5,002,572	-	-
Other current assets	1,341,398	-	**1,341,398**	607,810
	3,415,787	5,435,127	**8,850,914**	4,779,656
Long term investment (Note 16)	-	-	-	950,000
Capital assets (Note 5)	26,027,908	32,509,440	**58,537,348**	58,113,438
	$ 29,443,695	$ 37,944,567	**$ 67,388,262**	$ 63,843,094
LIABILITIES				
Current				
Accounts payable and accrued liabilities	4,323,318	65,000	**4,388,318**	2,737,623
Due to APF Management Inc. (Note 13)	685,988	-	**685,988**	289,717
Royalty distribution payable	-	1,570,659	**1,570,659**	736,240
Current portion of discontinued acquisition	-	-	-	2,742,270
	5,009,306	1,635,659	**6,644,965**	6,505,850
Discontinued acquisition liability (Note 16)	-	-	-	650,803
Future income taxes	4,652,982	-	**4,652,982**	-
Long-term debt (Note 8)	25,735,555	-	**25,735,555**	33,170,889
Site restoration liability	2,143,041	-	**2,143,041**	1,282,127
	$ 37,540,884	$ 1,635,659	**$ 39,176,543**	$ 41,609,669
EQUITY				
Share capital (Note 9)	10	-	**10**	10
Unitholders investment account (Note 10)	-	57,704,112	**57,704,112**	49,704,695
Retained earnings (deficit)	(8,097,199)	14,177,642	**6,080,443**	(5,797,293)
Cumulative royalty distributions declared	-	(35,572,846)	**(35,572,846)**	(21,673,987)
	(8,097,189)	36,308,908	**28,211,719**	22,233,425
	$ 29,443,695	$ 37,944,567	**$ 67,388,262**	$ 63,843,094

Approved by the Board

Martin Hislop
Director

Steven G. Cloutier
Director

Combined Statement of Operations and Retained Earnings (Deficit)

December 31	2000	1999
REVENUE		
Oil and gas	$ 44,046,732	$ 23,684,879
Royalties expense, net of ARTC	(8,529,767)	(3,897,849)
Other	927,722	1,021,834
	36,444,687	20,808,864
EXPENSES		
Operating	8,021,144	7,299,860
General and administrative	1,844,203	1,132,746
Management fee (Note 13)	993,245	464,709
Interest on long-term debt	1,882,285	1,955,201
Depletion and amortization	7,174,725	7,382,592
Site restoration	904,458	640,736
Capital and other taxes	164,230	98,063
	20,984,290	18,973,907
Operating income	15,460,397	1,834,957
Unusual item (loss) (Note 16)	210,212	(6,524,390)
Income (loss) before income taxes	15,670,609	(4,689,433)
Provision for future income taxes (Note 12)	1,406,000	-
Net income (loss) for the year	14,264,609	(4,689,433)
(Deficit) retained earnings, beginning of year	(5,797,293)	(975,086)
Dividend of 1% residual interest	(189,892)	(132,774)
Adjustment for change in accounting policy (Note 3)	(2,196,981)	-
Retained earnings (deficit) – End of year	$ 6,080,443	$ (5,797,293)
Net income (loss) per unit	$ 2.07	$ (0.80)
Net income (loss) per unit – fully diluted	$ 2.01	$ (0.80)

Combined Statement of Cash Flows

December 31	2000	1999
CASH PROVIDED BY (USED IN)		
Operating activities		
Net income (loss) for the year	$ 14,264,609	$ (4,689,433)
Add items not affecting cash		
Depletion and amortization	7,174,725	7,382,592
Site restoration	904,458	640,736
Future income taxes	1,406,000	-
Funds flow from operations	23,749,792	3,333,895
Change in non-cash working capital		
Accounts receivable	(3,367,989)	(1,159,869)
Other current assets	(733,588)	(110,598)
Accounts payable and accrued liabilities	1,826,914	512,319
Due to APF Management	396,271	(5,336)
Royalty distribution payable	834,419	29,449
Current portion of discontinued acquisition (Note 16)	(2,742,270)	2,742,270
Net change in non-cash working capital	(3,786,243)	2,008,235
Royalty distributions declared	(13,898,859)	(9,188,279)
	6,064,690	(3,846,149)
Investing activities		
Site restoration (Note 6)	(43,544)	(231,591)
Purchase of oil and natural gas properties (Note 7)	(18,941,517)	(7,323,959)
Changes in non-cash working capital items		
Accounts payable	(176,214)	171,387
	(19,117,731)	(7,152,572)
Proceeds on sale of properties	12,392,878	2,326,397
Long term asset investment – net	950,000	(950,000)
	(5,818,397)	(6,007,766)
Financing activities		
Discontinued acquisition liability	(650,803)	650,803
Issue of units for cash	8,925,542	-
Issue of units for cash under stock options	216,398	-
Unit issue costs	(1,142,523)	(235,342)
Proceeds on issue of long-term debt – net		
Current expenditures	-	5,306,843
Discontinued acquisition	-	4,041,523
Repayment of long-term debt – net	(7,435,334)	-
Dividend of 1% residual interest	(189,892)	(132,774)
	(276,612)	9,631,053
Change in cash during the year	(30,319)	(222,862)
Cash – Beginning of year	96,550	319,412
Cash – End of year	$ 66,231	$ 96,550

Cash payments related to certain items are as follows:	2000	1999
Cash payments		
Interest	2,346,730	2,112,942
Dividends	147,960	110,499
Royalty distributions	13,064,245	9,158,828
Capital taxes	164,230	98,063

Combined Statement of Royalty Distribution

(see Note 4)

December 31	2000	1999
Oil and gas sales	**$ 44,046,732**	$ 23,684,879
Other	**927,722**	1,021,834
Gross overriding royalties and lessor's royalties	**(4,124,993)**	(1,998,550)
	40,849,461	22,708,163
Less:		
Operating costs	**8,021,144**	7,299,860
General and administrative	**1,844,203**	1,132,746
Management fees	**993,245**	464,709
Debt service charges	**10,798,865**	1,955,201
Abandonment fund contribution	**43,544**	231,591
Capital and other taxes	**164,230**	98,063
Capital expenditures	**5,628,238**	3,293,097
Drawdown on credit facilities	**(5,628,238)**	(3,293,097)
	21,865,231	11,182,170
Income subject to the Royalty	**18,984,230**	11,525,993
99% of income subject to the Royalty	**18,794,388**	11,410,733
Crown charges	**(4,611,082)**	(2,211,413)
Alberta Royalty Tax Credit	**250,355**	331,107
	14,433,661	9,530,427
Working capital reserve	**(534,998)**	(342,148)
Distributable Income (after working capital reserve)	**13,898,663**	9,188,279
Income distributed to date	**(12,328,004)**	(8,452,039)
Royalty distribution payable	**$ 1,570,659**	$ 736,240
Distributable Income (after working capital reserve, before special distribution) (per unit)	**$ 1.65**	$ 1.56
Special Distributable Income per unit	**$ 0.35**	-

Notes to Combined Financial Statements

December 31, 2000 and 1999

The objective and integrity of data in these financial statements, including estimates and judgements relating to matters not concluded by year end, are the responsibility of management of APF Energy Trust ("Trust"). In management's opinion, the financial statements have been properly prepared within reasonable limits of materiality and within the framework of the Trust's accounting policies.

1 BASIS OF PRESENTATION

APF Energy Trust (the "Trust")

The Trust was a closed-end investment trust formed under the laws of the Province of Alberta. The beneficiaries of the Trust (the "Unitholders") are holders of royalty units issued by the Trust (the "Units"). The Trust was a limited purpose trust whose purpose was to invest principally in royalties granted by APF Energy Inc. On July 28, 1999 the Trust became an open-end investment trust which could invest in a variety of shares or debt.

APF Energy Inc. ("Energy")

Energy was incorporated and organized for the purpose of acquiring, developing, exploiting and disposing of oil and natural gas properties, including certain initial properties and granting a royalty thereon to the Trust.

The operations of the Trust and Energy have been combined commencing December 1, 1996 to present the operations of the properties owned by Energy on which the Royalty to the Trust is based. A statement of Royalty Distribution is presented to reconcile the property operations to the defined royalty and royalty distributions to the Trust Unitholders.

The Manager of the Trust, APF Energy Management Inc. ("Management") prepares the combined financial statements following accounting policies generally accepted in Canada. Although the Unitholders have the right to elect the majority of the directors of Energy, Management determined that combined rather than consolidated financial statements would provide the best presentation because there is no investor/investee relationship between the Trust and Energy. Both methods of reporting would give comparable information. The combined financial statements of the Trust and Energy will be referred to as "APF".

2 SIGNIFICANT ACCOUNTING POLICIES

Capital assets – oil and natural gas

APF follows the full cost method of accounting. All costs of acquiring oil and natural gas properties and related development costs are capitalized and accumulated in a cost centre. Maintenance and repairs are charged against earnings, and renewals and enhancements, which extend the economic life of the property, plant and equipment are capitalized. No general and administrative costs have been capitalized.

Gains and losses are not recognized upon disposition of oil and natural gas properties unless such a disposition would significantly alter the rate of depletion.

Ceiling test

APF places a limit on the aggregate cost of capital assets which may be carried forward for amortization against revenues of future periods (the "ceiling test"). The ceiling test is a cost recovery test whereby the capitalized costs less accumulated depletion and site restoration are limited to an amount equal to estimated undiscounted future net revenues from proven reserves based on year end prices, plus the unimpaired costs of non-producing properties less estimated future general and administrative expenses, site restoration costs, management fees, financing costs and income taxes related to Energy. Future distributions to Unitholders whether or not they are required under the Trust Indenture are not considered as future financing costs for purposes of the ceiling test. Costs and prices at the balance sheet dates are used. Any costs carried on the balance sheet in excess of the ceiling test limitation are charged to earnings.

Depletion and amortization

The provision for depletion and amortization of oil and natural gas assets including tangible equipment is calculated using the unit-of-production method based on the estimated working interest share of proven reserves before royalties. Reserves are converted to equivalent units on the basis of approximate relative energy content.

Site restoration and abandonment

The provision for estimated site restoration costs is determined using the unit-of-production method. Actual site restoration costs are charged against the accumulated provision.

Other equipment

All other equipment is carried at cost and is depreciated over the estimated useful life of the assets at annual rates varying from 10% to 30%.

Joint ventures

Substantially all oil and natural gas production and exploitation activities are conducted jointly with others. Accordingly, the accounts reflect APF's proportionate interest in these activities.

Trust per unit calculations

The per unit income (loss) and royalty calculations are based on the weighted average number of units outstanding during the period. (2000 – 6,888,012 units; 1999 – 5,889,922 units).

Cash distributions

Cash distributions are calculated on an accrual basis and are paid to the Unitholders based upon funds available for distribution.

Trust unit-based compensation plan

The Trust has a fixed Trust Unit option plan which is described in note 11. No compensation expense is recognized for this plan when Trust Units or Trust Unit options are issued to employees. Any consideration paid by employees on exercise of Trust Unit options or purchase of Trust Units is credited to Unitholders' investment account. If Trust Units or Trust Unit options are repurchased from employees, the excess of the consideration paid over the carrying amount of the Trust Units or Trust Unit options cancelled is charged to retained earnings.

Income taxes

The Trust is an inter vivos trust for income tax purposes. As such, the Trust is taxable on any taxable income which is not allocated to the Unitholders. The Trust intends to allocate all income to Unitholders. Should the trust incur any income taxes, the funds available for distribution will be reduced accordingly. Provision for income taxes is recorded in Energy at applicable statutory rates. Provision for income taxes is recorded in Energy using the liability method of accounting whereby the future income tax effect of any difference between the accounting and income tax basis of an asset or liability is booked.

Management estimates

The combined financial statements include certain management estimates that may require accounting adjustments based on future occurrences. The most significant estimates relate to depletion, amortization and ceiling test calculations for capital assets including future abandonment liabilities as they are based on engineering reserve estimates and estimated future costs. The estimate of the recoverable amount of the long term investment is subject to adjustment based on future occurrences.

3 CHANGE IN ACCOUNTING POLICY

Effective January 1, 2000, Energy and Trust adopted the liability method for accounting for income taxes as recommended by the Canadian Institute of Chartered Accountants (CICA). Under the liability method, Energy will record future income taxes for the effect of any difference between the accounting and income tax basis of an asset or liability. Energy has retrospectively without adjustment adopted the CICA recommendations by recording additional property, plant and equipment of $1 million and recording a decrease in retained earnings of $2.2 million and an increase in the future income tax liability of $3.2 million. The additions to property, plant and equipment will be amortized to income over future periods.

4 ROYALTY DISTRIBUTION

The Royalty is granted to the Trust pursuant to the Royalty Agreement. The Royalty consists of an entitlement to 99% of Royalty Income. The Royalty does not constitute an interest in land and the Trust is not entitled to take its share of production in kind. "Royalty Income" means Net Production Revenues less the aggregate of the Debt Service Charges, the Management Fees (to the extent Other Revenues are insufficient to pay the Management Fees), G&A and taxes or other applicable charges payable by Energy, less any advances made pursuant to the credit facilities of Energy to fund the payment of such costs and charges, which included changes to the working capital reserve and which, after July 1, 1998, provides for a working capital reserve to be maintained in the Trust.

"Net Production Revenue" will mean:

(a) the amount received by Energy in respect of the sale of its interest in all Petroleum Substances produced from the Properties, together with net profit or loss from commodity price swaps (but not including ARTC, proceeds of disposition of Properties or Other Revenues);

less:

(b) Operating Costs and all other expenditures paid or payable by or on behalf of Energy in respect of operating the Properties including, without limitation, the costs of gathering, treating, compressing, processing, transporting and marketing all Petroleum Substances produced from the Properties and all other amounts paid to third parties which are calculated with reference to production from the Properties including, without limitation, gross overriding royalties and lessors' royalties, but excepting Crown Royalties and other applicable charges;

(c) capital expenditures intended to improve or maintain production from the Properties, (but not to acquire Additional Properties or Replacement Properties), in excess of amounts borrowed or designated as Deferred Purchase Obligations in respect thereof, but not in excess of 10% of the annual net cash flow from the Properties;

(d) net contributions to Energy's Reclamation Fund and the Cash Reserve;

(e) costs otherwise reimbursed by proceeds of business interruption, property damage and third party liability insurance less any such proceeds;

(f) costs of generating Other Revenues; and

(g) amounts required to be paid to the Trustee pursuant to the Trust Indenture, including, without limitation, amounts to be paid pursuant to indemnification provisions.

Energy is required to pay to the Trust on each Cash Distribution Date 99% of Royalty Income received by Energy from the Properties for the period ending on the last day of the month immediately preceding the Cash Distribution Date.

The Trust pays Energy 99% of the Crown Royalties and other Crown charges in respect of production from or ownership of the Properties. Energy is at all times entitled to set off its right to be so reimbursed against its obligation to pay the Royalty.

Energy uses Other Revenues to pay Management Fees, purchase Permitted Investments, pay for Additional Properties, Replacement Properties and capital costs, for net losses, if any, from currency swaps and for general corporate purposes, or to repay borrowing for such purposes.

As and from the time of becoming an open-end Trust, the Trust includes in the calculation of the Royalty Distribution, 100% of income before depreciation, amortization and depletion from investments in shares, notes and other investments.

5 CAPITAL ASSETS, AT COST

2000	APF Energy Inc.	APF Energy Trust	2000 Combined
Property	**$ 37,395,902**	**$ 50,824,048**	**$ 88,219,950**
Accumulated depletion and depreciation	**11,367,994**	**18,314,608**	**29,682,602**
	$ 26,027,908	**$ 32,509,440**	**$ 58,537,348**

1999	APF Energy Inc.	APF Energy Trust	1999 Combined
Property	$ 30,480,955	$ 50,140,360	$ 80,621,315
Accumulated depletion and depreciation	(8,472,220)	(14,035,657)	(22,507,877)
	$ 22,008,735	$ 36,104,703	$ 58,113,438

6 SITE RESTORATION

Energy is responsible for future abandonment costs on all properties. At December 31, 2000 the future undiscounted estimated costs for the abandonment liabilities were $8,316,000, of which $2,143,041 has been provided for. The current year expense charged to the provision was $904,458. Actual payments for abandonment in 2000 were $43,544.

7 ACQUISITIONS

During 2000 and 1999, Energy purchased a number of Properties at various times throughout the years. The net acquisition of the Properties by Energy for December 31, 2000 and 1999 are summarized below:

	2000	1999
Purchase price of net properties acquired	**$ 1,926,852**	$ 1,444,185
Other capital expenditures	**4,621,783**	3,553,377
Total additions to oil and natural gas properties	**6,548,635**	4,997,562
Royalty acquired by Trust	**$ 683,689**	$ 1,393,663

8 LONG-TERM DEBT

	2000	1999
Bank loans	**$ 25,735,555**	$ 33,170,889

The bank loans bear interest based on a sliding scale tied to Energy's debt to cash flow ratio, from a minimum of the bank's prime rate plus 0.125% to a maximum of the prime rate plus 1.5% (1999 – bank prime plus 0.5%) or where available, at Banker's Acceptances rates plus a stamping fee of 1.125% to 1.75%. Prime rate at December 31, 2000 was 7.50%, Banker's Acceptances were 5.92 – 5.98% (1999, prime rate – 6.50%, Banker's Acceptances – 5.12 – 5.30%).

The maximum amount of borrowing currently available under the bank loan facilities is $42,000,000, comprised of a $40,000,000 revolving operating demand loan and a $2,000,000 treasury risk line. The credit facility may be drawn down or repaid at any time but there are no scheduled repayment terms except that the acquisition facility provides for monthly repayments over the half-life of the reserves being financed with repayment commencing the month following drawdown. Although the bank loan is payable on demand, the bank has indicated that it does not intend to demand payment in the next fiscal year.

The loans are secured by a floating charge debenture on all petroleum and natural gas assets acquired, an Assignment of Book Debts and assignment of material gas contracts.

9 SHARE CAPITAL AND DEFICIT FOR ENERGY

Share capital

Authorized

Unlimited number of common shares

Issued

	2000		1999	
	Shares	**Amount**	Shares	Amount
Balance at end of year	**10**	**$ 10**	10	$ 10

Deficit

Deficit, December 31, 1998	$ 6,573,435
Loss for the year ended December 31, 1999	2,991,212
Dividend of 1% residual interest	132,774
Deficit December 31, 1999	$ 9,697,421
(Income) for the year ended December 31, 2000	(3,987,095)
Dividend of 1% residual interest - December 31, 2000	189,892
Prior period adjustment	2,196,981
Deficit December 31, 2000	$ 8,097,199

10 ROYALTY UNITHOLDERS INVESTMENT ACCOUNT

	2000		1999	
	Units	**Amount**	Units	Amount
Units outstanding at end of the year	**7,139,357**	**$ 63,358,758**	5,889,922	$ 54,216,818
Costs of Unit issue	**-**	**(5,654,646)**	-	(4,512,123)
	7,139,357	**$ 57,704,112**	5,889,922	$ 49,704,695

The holders of Units are entitled to vote at any meeting of the Unitholders.

The Trust has a Trust Unit Incentive Plan which provides for options to acquire units to be issued to directors, officers, employees and consultants of Energy and Management. During 1996, 100,000 options were granted at a price of $10.00 per unit which expire on December 17, 2001. Of these, 27,000 have expired. During 1997, 6,000 options were granted at a price of $9.00. During 1998, 6,000 options were granted at prices of $9.25 and $8.40. In 1999, 79,000 options were granted at a price of $8.00. In 2000, 89,000 options were granted at prices of $7.15 (86,500) and $8.85 (2,500).

In 1999, the Trust created a Unitholders' Rights Plan and authorized the issuance of one right in respect of each Unit outstanding. Each right would allow Unitholders in specified circumstances, to acquire, on payment of an exercise price of $50.00, the number of Units having an aggregate market price equal to twice the exercise price of the rights.

In 1999, the Trust issued 594,564 Warrants, 80,346 of which may be converted into 80,346 Units and the balance were cancelled. In 2000, the remaining 80,346 Warrants were cancelled. See Note 16.

11 TRUST UNIT OPTION PLAN

Pursuant to a Trust Unit Incentive Plan dated December 17, 1996 and amended February 1, 1998 (the "Plan"), the directors, management, employees and consultants of Energy and Management may be granted options to acquire Units of the Trust. The exercise price for each option is the market price of the Units at the time the option is granted. Options granted prior to February 1, 1998 vested immediately, while options granted on or after February 1, 1998 vest in one-third increments on the first, second and third anniversaries of their grant. The maximum term for each grant of options is five years.

A summary of the status of the Plan as of December 31, 2000 and 1999 is as follows:

	2000		1999	
Options	**Units**	**Weighted Average Price**	Units	Weighted Average Price
Outstanding at beginning of year	**174,500**	**$ 9.01**	95,500	$ 9.85
Granted	**89,000**	**7.20**	79,000	8.00
Exercised	**(26,759)**	**8.09**	-	-
Forfeited	**(21,834)**	**8.92**	-	-
Outstanding at end of year	**214,907**	**8.38**	174,500	9.01
Options exercisable at year end	**93,842**	**$ 9.57**	87,460	$ 9.94

The following table summarizes information about fixed Trust Units options outstanding at December 31, 2000:

Options outstanding			Options exercisable		
Range of exercise prices	Number outstanding at December 31, 2000	Weighted average remaining contractual life (years)	Weighted average exercise price	Number exercisable at December 31, 2000	Weighted average price
$ 7.00 – 7.99	81,500	4.18	$ 7.15	-	-
$ 8.00 – 9.00	56,407	3.21	8.06	18,507	8.03
$ 9.01 – 10.00	77,000	1.03	9.94	75,335	9.96
	214,907			93,842	

12 INCOME TAXES

Energy's pre-tax corporate income was $5,393,093 at December 31, 2000 (a loss of $2,991,212 – December 31, 1999). Upon adoption of CICA Handbook Section 3465, Energy retroactively without adjustment recorded a future tax debit effective January 1, 2000 of $1,859,218 to recognize the future tax benefits of the tax losses and recorded a future tax liability of $4,056,199 on capital assets. Energy has approximately $10,588,601 of unused tax pools at December 31, 2000 ($8,541,000 – December 31, 1999) available to be used to offset future taxable income subject to certain restrictions of the Income Tax Act.

Energy had approximately $2,105,638 in non-capital losses at December 31, 2000 ($5,879,000 – December 31, 1999).

Estimated non-capital losses at December 31, 2000:

	Expire
$ 2,105,638	2006
$ 2,105,638	

Future tax recorded on the balance sheet results from:	
Recording future taxes for tax losses that are likely to be utilized	$ (942,062)
Difference between accounting and income tax assets and liabilities being primarily capital assets	5,595,044
	$ 4,652,982

The Unitholders are responsible for their own income taxes. Distributions will be a combination of taxable income and a return of capital in the year received. Generally, when the Trust has no taxable income prior to the deduction of distributions, distributions will not be taxable but will be a return of capital which reduces the Unitholders' adjusted cost base in those years.

	APF Energy Inc.	
December 31	**2000**	1999
Energy's pre-tax corporate income (loss)	**$ 5,393,093**	$ (2,991,212)
Statutory tax rate	**44.74%**	44.75%
Expected tax provision	**2,412,870**	(1,338,567)
Non-deductible crown payments	**132,847**	9,996
Resource allowance	**(1,206,451)**	(166,786)
Depletion of assets with no tax base	**-**	603,160
Unrecognized deferred tax asset	**-**	882,655
Other	**66,734**	9,542
Income tax provision	**$ 1,406,000**	$ -

December 31	APF Energy Trust 2000	1999
Trust income (loss) before income tax	**$ 10,277,487**	$ (1,698,221)
Depletion and amortization	**4,278,951**	4,725,881
Crown royalties (Net of ARTC)	**4,360,727**	1,876,961
Resource allowance	**(4,395,756)**	(2,831,598)
Non-deductible expenses relating to an unusual item	**(210,212)**	6,470,590
Distributions deducted for income tax purposes	**(8,117,766)**	(3,095,887)
Other deductions for income tax purposes	**(6,193,431)**	(5,447,726)
Net loss for actual tax purposes	**$ -**	$ -

The Trust has $5,524,073 of capital loss to be used against any capital gains.

During 2000 there was Nil taxable income in the Trust ($Nil, 1999).

Distributions paid are deducted from taxable income only to the extent needed to reduce taxable income in the Trust to zero. Generally, the distributions deducted for the Trust tax return are taxable income to the Unitholders.

Taxable income of the Trust is comprised of income from the royalty, adjusted for crown royalties and resource allowance, less deductions for Canadian oil and natural gas property expense (COGPE), which is claimed at a rate of 10% on a declining balance basis and issue costs which are claimed at 20% per year on a straight-line basis. Any losses which occur in the Trust must be retained in the Trust and may be carried forward and deducted from taxable income for a period of seven years. The COGPE during 2000 and 1999 resulted from the purchase of royalty interests.

The amount of COGPE and issue costs remaining in the Trust are as follows:

December 31	**2000**		1999	
	Per Trust Unit	**Amount**	Per Trust Unit	Amount
COGPE	**$ 4.87[(1)]**	**$ 34,768,480**	$ 6.44	$ 37,908,897
Issue costs	**0.30**	**2,150,142**	0.37	2,150,618
	$ 5.17	**$ 36,918,622**	$ 6.81	$ 40,059,515

(1) Per Trust Unit amount is based on the actual number of Trust Units outstanding at year end of 7,139,357 (1999 – 5,889,922).

13 RELATED PARTY TRANSACTIONS

Under the terms of the APF Trust Management Agreement, Management manages the business of the Trust and administers all matters relating to the Trust in exchange for a Management Fee of $100. The Manager is also paid a Structuring Fee of 1.5% for its role in identifying and acquiring oil and natural gas properties; $306,713 in Structuring Fees were included in the purchase price of properties for the year ended December 31, 2000 (1999 - $94,767). For the year ended December 31, 2000, the Manager was paid $993,245 (1999 - $464,709) in Management Fees under an agreement with Energy.

During the year, Energy reimbursed Management for administrative expenses on a cost recovery basis. For the year ended December 31, 2000, Energy paid $1,502,334, (1999 - $882,293) as administrative costs to Management based on an average of $1.49 (1999 - $0.88) per barrel of oil equivalent produced.

The Management Purchasers had agreed to participate in the acquisition of common shares of United Gas Management Inc. if the proposed transaction proceeded to closing. They received a Structuring Fee on the acquisition of common shares of United and purchased their share of 2.6% of the common shares. See Note 16.

14 FINANCIAL INSTRUMENTS

The Trust's financial instruments that are included in the balance sheet are comprised of cash, accounts receivable, and all liabilities except site restoration liability.

a) Commodity hedging

As at December 31, 2000, Energy had several natural gas swaps in place amounting to 1,002,000 Mcf of gas at an average price of CDN$5.78 per Mcf until October 31, 2001. As at December 31, 1999, Energy had no natural gas swaps in place.

If Energy had unwound its position at December 31, 2000, it would have recognized a loss of $ 7.94 million (1999 – loss of $Nil) with respect to its natural gas hedges.

At December 31, 2000, Energy had several oil swaps in place amounting to 17,739 barrels of oil at an average price of $31.19 (U.S.) per barrel until March, 2001. At December 31, 1999, Energy had several oil swaps in place amounting to 36,182 barrels of oil at an average price of $23.22 (U.S.) per barrel until April, 2000.

If Energy had unwound its position at December 31, 2000, it would have recognized a gain of $95,081 (1999 - $138,719) with respect to its oil hedges.

b) Currency hedging

At December 31, 2000, Energy had no forward foreign currency exchange contracts in place. The unrealized loss at December 31, 1999 was $Nil.

c) Fair values of financial assets and liabilities

The fair values of financial instruments that are included in the balance sheet, including long-term borrowings, approximate their carrying amount due to the short-term maturity of those instruments and the floating prime rate applied to long-term borrowings.

d) Credit risk

A substantial portion of the Energy's accounts receivable are with customers in the oil and natural gas industry and are subject to normal industry credit risks.

e) Interest rate risk

At December 31, 2000, the increase or decrease in net earnings or loss before income taxes for each 1% change in interest rates on floating rate debt amounted to $257,356 (1999 - $331,709).

f) Foreign exchange risk

At December 31, 1999 there was a foreign exchange risk on $Nil (U.S.) for amounts related to unusual items (1999 - $1,900,000).

15 CONTINGENCIES

Energy is involved in certain legal actions which have occurred in the ordinary course of business. Management is of the opinion that losses, if any, arising from such legal actions would not have a material effect on these financial statements.

16 UNUSUAL ITEM – COSTS RELATED TO UNSUCCESSFUL ACQUISITION

Acting as an agent for the Trust, Energy entered into an agreement dated July 30, 1999 to purchase a 48% interest in a gas marketing company for U.S. $24,000,000 (Cdn. $35,323,200). In addition, the Trust would be obligated for future cash advances secured by notes. To finance this acquisition and future capital obligations the Trust filed a preliminary prospectus to raise the required funds. A final receipt for this prospectus was not received and the transaction was not completed.

Energy, acting as agent, provided a letter of credit of U.S. $1,300,000 (Cdn. $1,876,290) which, on discontinuance of the transaction, was converted into a 2.6% interest in the target company. As the target company is private and has no history of earnings this amount was written down to Cdn. $950,000, which is the estimated recoverable amount, resulting in a loss of Cdn. $878,320. Management received a Structuring Fee on the U.S. $1,300,000 and purchased 4% of the 2.6% interest in the target company.

In pursuing the transaction, Energy acting as agent provided the following funding which has been expensed:

		U.S.$	CDN$
September 21, 1999	agreement to advance funds	$ 600,000	$ 886,500
October 25, 1999	agreement to advance funds	2,000,000	2,947,512
September 21, 1999	guarantee	600,000	865,900
Not yet issued 80,346	Units valued @ 8.10	500,000	650,803
Total		$ 3,700,000	$ 5,350,715

In addition, the company expensed Cdn. $295,355 in costs related to the unsuccessful equity issue. For income tax purposes, the majority of the loss will be a capital item. The total loss of $6,524,390 was recorded in the statement of operations and the remaining portion of the obligation was recorded as $3,393,073 of discontinued acquisition liability.

The remaining portion of the obligation was extinguished as well as the return of the 2.6% interest in the target company in fiscal 2000 with a recovery of $210,212 of the previously recorded losses.

17 SUBSEQUENT EVENTS

a) Agency Agreement and Prospectus Filing (audited)

The Trust, APF and the Agents entered into an Agency Agreement pursuant to which the Agents agreed to offer and the Trust agreed to issue and sell up to 2,870,000 Units at the price of $10.00 per Unit. Closing of the offering and the issue of 2,870,000 Units took place on March 1, 2000.

The estimated net proceeds from this offering (assuming the over-allotment option is not exercised) will be in the amount of $26,628,000, after deducting expenses of the issue and after Agents' commissions.

b) Pre-Acquisition Agreement with Alliance Energy Inc.

The Trust has entered into an agreement with Alliance Energy Inc. ("Alliance") pursuant to which the Trust or Energy will offer to acquire all outstanding shares of Alliance. The offer will consist of cash of $2.02 per Alliance common share to a maximum of $35,328,531 or, at the option of the Alliance shareholder, 0.201 Trust Units, to a maximum of 2,197,048 Trust Units, in each case subject to proration. The debt of Alliance, in the amount of $9,074,000 (which reflects an amount of $4,574,000 borrowed by Alliance to be paid as a deposit on the Saskatchewan Agreement) will also be assumed. The estimated purchase equation using the November 30, 2000 financial statements of Alliance as a base and assuming 80% cash paid and 20% Trust Units issued is as follows:

Working capital	$ (3,967,460)
Capital assets	57,529,108
Long-term debt	(3,200,000)
Future income taxes	(4,087,879)
Provision for site restoration costs	(505,071)
Net	$ 45,768,698
Consideration	
870,891 Units at $10.05	$ 8,752,453
Bank financing	35,009,811
Due to related party	656,434
Acquisition costs	$ 1,350,000
	$ 45,768,698

The above amounts do not include a proposed acquisition of Saskatchewan assets by Alliance which if consummated would be for the purchase of properties for approximately $42,940,000.

Corporate Information

HEAD OFFICE

Until June 30, 2001: 2650, 605 - 5th Avenue S.W., Calgary, Alberta T2P 3H5
Effective July 1, 2001: 2100, 144 - 4th Avenue S.W., Calgary Alberta T2P 3N4
Telephone: (403) 294-1000
Toll Free Telephone: (800) 838-9206
Fax: (403) 294-1074
Internet: www.apfenergy.com
E-Mail: invest@apfenergy.com

DIRECTORS AND OFFICERS OF APF ENERGY INC.

Don Engle, Independent Director*

William Dickson, Independent Director*

Daniel Mercier, Independent Director

Martin Hislop, Director*
President & Chief Executive Officer

Steven Cloutier, Director
Executive Vice President,
Chief Operating Officer

Bonnie Nicol
Vice President, Operations

Ken Pretty
Vice President,
Corporate Development and Land

** Member of Audit Committee*

LEGAL COUNSEL

Parlee McLaws
Calgary, Alberta

BANK

National Bank of Canada
Calgary, Alberta

ENGINEERING CONSULTANTS

Gilbert Laustsen Jung Associates Ltd.
Calgary, Alberta

TRUSTEE, REGISTRAR & TRANSFER AGENT

The Trust Company of Bank of Montreal
Calgary, Alberta

AUDITORS

PricewaterhouseCoopers LLP
Calgary, Alberta

STOCK EXCHANGE LISTING

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APF ENERGY TRUST

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2650, 605 - 5th Avenue S.W., Calgary, Alberta T2P 3H5
New address effective July 1, 2001: 2100, 144 - 4th Avenue S.W., Calgary Alberta T2P 3N4
Telephone: (403) 294-1000 Toll Free Telephone: (800) 838-9206 Fax: (403) 294-1074
Internet: www.apfenergy.com E-Mail: invest@apfenergy.com